

Alberta Reliability Standard

Transmission System Planning Performance Requirements

TPL-001-AB-5.1

A. Introduction

1. Title: Transmission System Planning Performance Requirements
2. Number: TPL-001-AB-5.1
3. Purpose: Establish **transmission system** planning performance requirements within the planning horizon to develop a **transmission system** that will operate reliably over a broad spectrum of system conditions and following a wide range of probable **contingencies**.
4. Applicability:
 - 4.1. Functional Entity:
 - 4.1.1. the **ISO**.
5. Effective Date: See Implementation Plan TPL-PLAN-AB-1, *Implementation Plan for TPL-001-AB-5.1*

B. Requirements and Measures

- R1.** The **ISO** must maintain system models within its respective area for performing the studies needed to complete its **planning assessment**. The models must use data consistent with that provided in accordance with Section 503.21 of the **ISO rules**, *Reporting Facility Modelling Data*, supplemented by other sources as needed, including items represented in the **corrective action plan**, and must represent projected system conditions. This establishes Category P0 as the normal system condition in Table 1: *[Alberta Risk Rating: High] [Time Horizon: Long-term Planning]*
- 1.1. System models must represent:
 - 1.1.1. Existing facilities.
 - 1.1.2. New planned facilities and changes to existing facilities.
 - 1.1.3. Real and reactive load forecasts.
 - 1.1.4. Resources (supply or **demand** side) required for load.
- M1.** The **ISO** must provide evidence, in electronic or hard copy format, that it is maintaining system models within its respective area, using data consistent with Section 503.21 of the **ISO rules**, *Reporting Facility Modelling Data*, including items represented in the **corrective action plan**, representing projected system conditions, and that the models represent the required information in accordance with Requirement R1.
- R2.** The **ISO** must prepare an annual **planning assessment** of its portion of the **bulk electric system**. This **planning assessment** must use current or qualified past studies, as indicated in Requirement R2, Part 2.6, and notices, information, and analyses, document assumptions, and document summarized results of the steady state analyses, short circuit analyses, and stability analyses. *[Alberta Risk Rating: High] [Time Horizon: Long-term Planning]*
- 2.1. For the **planning assessment**, the **near-term transmission planning horizon** portion of the steady state analysis must be assessed annually by the **ISO** and be supported by current

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annual studies or qualified past studies as indicated in Requirement R2, Part 2.6. Qualifying studies need to include the following conditions:

- 2.1.1. System peak load for either year one or year two, and for year five.
- 2.1.2. System **off peak** load for one of the five years.
- 2.1.3. For each of the studies described in Requirement R2, Parts 2.1.1 and 2.1.2, sensitivity case(s) must be utilized by the **ISO** to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the **planning assessment** must vary one or more of the following conditions by a sufficient amount to stress the system within a range of credible conditions that demonstrate a measurable change in system response:
 - Real and reactive forecasted load.
 - Expected transfers.
 - Expected in service dates of new or modified **transmission facilities**.
 - **Reactive power** resource capability.
 - **Generating unit** and **aggregated generating facility** additions, retirements, or other dispatch scenarios.
 - Controllable loads and **demand-side** management.
 - Duration or timing of known transmission outages.
- 2.1.4. When known outages(s) of **generating unit(s)**, **aggregated generating facility(ies)**, or **transmission facility(ies)** are planned in the **near-term transmission planning horizon**, the impact of selected known outages on system performance must be assessed. These known outage(s) must be selected for assessment consistent with a documented outage coordination procedure or technical rationale by the **ISO**. Known outage(s) must not be excluded solely based upon outage duration. The assessment must be performed for the P0 and P1 categories identified in Table 1 with the system peak or **off peak** conditions that the system is expected to experience when the known outage(s) are planned. The performance assessment is equivalent to that of planning events P3 and P6. This assessment must include, at a minimum, known outages expected to produce more severe system impacts on the **ISO's** portion of the **bulk electric system**. Past or current studies may support the selection of known outage(s), if the study(s) has comparable post-**contingency** system conditions and configuration such as those following P3 or P6 category events in Table 1.
- 2.1.5. When a **legal owner** of a **transmission facility's** spare equipment strategy could result in the unavailability of major transmission equipment that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on system performance must be assessed by the **ISO**. Based upon this assessment, an analysis must be performed by the **ISO** for the P0, P1, and P2 categories identified in Table 1 with the conditions that the system is expected to experience during the possible unavailability of the long lead time equipment.

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- 2.2.** For the **planning assessment**, the **long-term transmission planning horizon** portion of the steady state analysis must be assessed annually by the **ISO** and be supported by the following annual current study, supplemented with qualified past studies as indicated in Requirement R2, Part 2.6:
- 2.2.1.** A current study assessing expected system peak load conditions for one of the years in the **long-term transmission planning horizon** and the rationale for why that year was selected.
- 2.3.** The short circuit analysis portion of the **planning assessment** must be conducted annually addressing the **near-term transmission planning horizon** and can be supported by current or past studies as qualified in Requirement R2, Part 2.6. The analysis must be used to determine whether circuit breakers have interrupting capability for **faults** that they will be expected to interrupt using the system short circuit model with any planned **generating unit** and **aggregated generating facility** and **transmission facilities** in service which could impact the study area.
- 2.4.** For the **planning assessment**, the **near-term transmission planning horizon** portion of the stability analysis must be assessed annually by the **ISO** and be supported by current or past studies as qualified in Requirement R2, Part 2.6. The following studies are required:
- 2.4.1.** System peak load for one of the five years. System peak load levels must include a load model which represents the expected dynamic behavior of loads that could impact the study area, considering the behavior of induction motor loads. An aggregate system load model which represents the overall dynamic behavior of the load is acceptable.
- 2.4.2.** System **off peak** load for one of the five years.
- 2.4.3.** For each of the studies described in Requirement R2, Parts 2.4.1 and 2.4.2, sensitivity case(s) must be utilized by the **ISO** to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the **planning assessment** must vary one or more of the following conditions by a sufficient amount to stress the system within a range of credible conditions that demonstrate a measurable change in performance:
- Load level, load forecast, or dynamic load model assumptions.
 - Expected transfers.
 - Expected in service dates of new or modified **transmission facilities**.
 - **Reactive power** resource capability.
 - **Generating unit** and **aggregated generating facility** additions, retirements, or other dispatch scenarios.
- 2.4.4.** When known outage(s) of **generating unit(s)**, **aggregated generating facility(ies)** or **transmission facility(ies)** are planned in the **near-term transmission planning horizon**, the impact of selected known outages on system performance must be assessed. These known outage(s) must be selected for assessment consistent with a documented outage coordination procedure or technical rationale by the **ISO**. Known outage(s) must not be excluded solely based upon outage duration. The assessment

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must be performed for the P1 categories identified in Table 1 with the system peak or **off peak** conditions that the system is expected to experience when the known outage(s) are planned. This assessment must include, at a minimum, those known outages expected to produce more severe system impacts on the **ISO's** portion of the **bulk electric system**. Past or current studies may support the selection of known outage(s), if the study(ies) has comparable post-**contingency** system conditions and configuration such as those following P3 or P6 category events in Table 1.

2.4.5. When the **legal owner** of a **transmission facility's** spare equipment strategy could result in the unavailability of major transmission equipment that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on system performance must be assessed by the **ISO**. Based upon this assessment, an analysis must be performed by the **ISO** for the selected P1 and P2 category events identified in Table 1 for which the unavailability is expected to produce more severe system impacts on its portion of the **bulk electric system**. The analysis must simulate the conditions that the system is expected to experience during the possible unavailability of the long lead time equipment.

- 2.5.** For the **planning assessment**, the **long-term transmission planning horizon** portion of the stability analysis must be assessed by the **ISO** to address the impact of proposed material **generating unit** or **aggregated generating facility** additions or changes in that timeframe and be supported by current or past studies as qualified in Requirement R2, Part 2.6 and must include documentation to support the technical rationale for determining material changes.
- 2.6.** Past studies may be used by the **ISO** to support the **planning assessment** if they meet the following requirements:
- 2.6.1.** For steady state, short circuit, or stability analysis, the study must be five calendar years old or less, unless a technical rationale can be provided to demonstrate that the results of an older study are still valid.
- 2.6.2.** For steady state, short circuit, or stability analysis, no material changes have occurred to the system represented in the study. Documentation to support the technical rationale for determining material changes must be included.
- 2.7.** For planning events shown in Table 1, when the analysis indicates an inability of the system to meet the performance requirements in Table 1, the **ISO's planning assessment** must include **corrective action plan(s)** addressing how the performance requirements will be met. Revisions to the **corrective action plans** are allowed in subsequent **planning assessments**, but the planned system must continue to meet the performance requirements in Table 1. **Corrective action plan(s)** do not need to be developed solely to meet the performance requirements for a single sensitivity case analyzed in accordance with Requirements R2, Parts 2.1.3 and 2.4.3. The **corrective action plan(s)** must:
- 2.7.1.** List system deficiencies and the associated actions needed to achieve required system performance. Examples of such actions include:
- Installation, modification, retirement, or removal of **transmission facilities, generating units, or aggregated generating facilities** and any associated equipment.

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- Installation, modification, or removal of **protection systems** or **remedial action schemes**.
 - Installation or modification of automatic generating unit or aggregated generating facility tripping as a response to a single or multiple **contingencies** to mitigate stability performance violations.
 - Installation or modification of manual and automatic generating unit or aggregated generating facility runback/tripping as a response to a single or multiple **contingencies** to mitigate steady state performance violations.
 - Use of **operating procedures** specifying how long they will be needed as part of the **corrective action plan**.
 - Use of rate applications, **demand-side management**, new technologies, or other initiatives.
- 2.7.2.** Include actions to resolve performance deficiencies identified in multiple sensitivity studies or provide a rationale for why actions were not necessary.
- 2.7.3.** If situations arise that are beyond the control of the **ISO** that prevent the implementation of a **corrective action plan** in the required timeframe, then the **ISO** is permitted to utilize **non-consequential load loss** to correct the situation that would normally not be permitted in Table 1, provided that the **ISO** documents that it is taking actions to resolve the situation. The **ISO** must document the situation causing the problem, alternatives evaluated, and the use of **non-consequential load loss**.
- 2.7.4.** Be reviewed in subsequent annual **planning assessments** for continued validity and implementation status of identified system facilities and **operating procedures**.
- 2.8.** For short circuit analysis, if the short circuit current interrupting duty on circuit breakers determined in Requirement R2, Part 2.3 exceeds their **equipment rating**, the **ISO** must include a **corrective action plan** to address the **equipment rating** in the **planning assessment**. The **corrective action plan** must:
- 2.8.1** List system deficiencies and the associated actions needed to achieve required system performance.
 - 2.8.2** Be reviewed in subsequent annual **planning assessments** for continued validity and implementation status of identified system facilities and **operating procedures**.
- M2.** The **ISO** must provide dated evidence that it has prepared an annual **planning assessment** of its portion of the **bulk electric system** in accordance with Requirement R2. Evidence may include electronic or hard copies of its annual **planning assessment** or other equivalent evidence.
- R3.** For the steady state portion of the **planning assessment**, the **ISO** must perform studies for the **near-term** and **long-term transmission planning horizon** in Requirement R2, Parts 2.1, and 2.2. The studies must be based on computer simulation models using data provided in Requirement R1. *[Alberta Risk Rating: Medium] [Time Horizon: Long-term Planning]*
- 3.1.** Studies must be performed for planning events to determine whether the **bulk electric system** meets the performance requirements in Table 1 based on the **contingency** list created in Requirement R3, Part 3.4.

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- 3.2.** Studies must be performed to assess the impact of the extreme events which are identified by the list created in Requirement R3, Part 3.5. If the analysis concludes there is **cascading** caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) must be conducted.
- 3.3. Contingency** analyses for Requirement R3, Parts 3.1 and 3.2 must:
- 3.3.1.** Simulate the removal of all **system elements** that the **protection system** and other automatic controls are expected to disconnect for each **contingency** without **operator** intervention. The analyses must include the impact of subsequent:
- 3.3.1.1.** Tripping of **generating units** and **aggregated generating facilities** where simulations show their bus voltages or high side of their step-up transformer voltages are less than known or assumed minimum **generating unit** steady state or ride through voltage limitations. Include in the assessment any assumptions made.
- 3.3.1.2.** Tripping of transmission **system elements** where relay loadability limits are exceeded.
- 3.3.2.** Simulate the expected automatic operation of existing and planned devices designed to provide steady state control of electrical system quantities when such devices impact the study area. These devices may include equipment such as phase-shifting transformers, load tap changing transformers, and switched capacitors and inductors.
- 3.4.** Those planning events in Table 1 that are expected to produce more severe system impacts on its portion of the **bulk electric system** must be identified, and a list of those **contingencies** to be evaluated for system performance in Requirement R3, Part 3.1 created. The rationale for those **contingencies** selected for evaluation must be available as supporting information.
- 3.4.1.** The **ISO** must coordinate with adjacent planning coordinators and **transmission planners** to allow the **ISO** to ensure that **contingencies** on adjacent systems, which may impact the **ISO's** system, are included in the **contingency** list.
- 3.5.** Those extreme events in Table 1 that are expected to produce more severe system impacts must be identified and a list created of those events to be evaluated in Requirement R3, Part 3.2. The rationale for those **contingencies** selected for evaluation must be available as supporting information.
- M3.** The **ISO** must provide dated evidence. Evidence may include electronic or hard copies of the studies utilized in preparing the **planning assessment**, or other equivalent evidence in accordance with Requirement R3.
- R4.** For the stability portion of the **planning assessment**, as described in Requirement R2, Parts 2.4 and 2.5, the **ISO** must perform the **contingency** analyses listed in Table 1. The studies must be based on computer simulation models using data provided in Requirement R1. *[Alberta Risk Rating: Medium]*
[Time Horizon: Long-term Planning]
- 4.1.** Studies must be performed for planning events to determine whether the **bulk electric system** meets the performance requirements in Table 1 based on the **contingency** list

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created in Requirement R4, Part 4.4.

- 4.1.1. For planning event P1: No **generating unit** or **aggregated generating facility** must pull out of synchronism. A **generating unit** or **aggregated generating facility** being disconnected from the system by **fault** clearing action or by a **remedial action scheme** is not considered pulling out of synchronism.
- 4.1.2. For planning events P2 through P7: When a **generating unit** or **aggregated generating facility** pulls out of synchronism in the simulations, the resulting apparent impedance swings must not result in the tripping of any transmission **system elements** other than the **generating unit** or **aggregated generating facility** and its directly connected facilities.
- 4.1.3. For planning events P1 through P7: Power oscillations must exhibit acceptable damping as established by the **ISO**.
- 4.2. Studies must be performed to assess the impact of the extreme events which are identified by the list created in Requirement R4, Part 4.5. If the analysis concludes there is **cascading** caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event(s) must be conducted.
- 4.3. **Contingency** analyses for Requirement R4, Parts 4.1 and 4.2 must:
 - 4.3.1. Simulate the removal of all **system elements** that the **protection system** and other automatic controls are expected to disconnect for each **contingency** without **operator** intervention. The analyses must include the impact of subsequent:
 - 4.3.1.1. Successful high speed (less than one second) reclosing and unsuccessful high speed reclosing into a **fault** where high speed reclosing is utilized.
 - 4.3.1.2. Tripping of **generating units** and **aggregated generating facilities** where simulations show their bus voltages or high side of their step-up transformer voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.
 - 4.3.1.3. Tripping of transmission lines and transformers where transient swings cause **protection system** operation based on generic or actual relay models.
 - 4.3.2. Simulate the expected automatic operation of existing and planned devices designed to provide dynamic control of electrical system quantities when such devices impact the study area. These devices may include equipment such as generating unit or aggregated generating facility exciter control and power system stabilizers, static var compensators, power flow controllers, and DC transmission controllers.
- 4.4. Those planning events in Table 1 that are expected to produce more severe system impacts on its portion of the **bulk electric system**, must be identified, and a list created of those **contingencies** to be evaluated in Requirement R4, Part 4.1. The rationale for those **contingencies** selected for evaluation must be available as supporting information.
 - 4.4.1. The **ISO** must coordinate with adjacent planning coordinators and **transmission planners** to ensure that **contingencies** on adjacent systems which may impact the **ISO's** systems, are included in the **contingency** list.

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- 4.5.** Those extreme events in Table 1 that are expected to produce more severe system impacts must be identified and a list created of those events to be evaluated in Requirement R4, Part 4.2. The rationale for those **contingencies** selected for evaluation must be available as supporting information.
- M4.** The **ISO** must provide dated evidence. Evidence may include electronic or hard copies of the studies utilized in preparing the **planning assessment** or other equivalent evidence in accordance with Requirement R4.
- R5.** The **ISO** must have criteria for acceptable system steady state voltage limits, post-**contingency** voltage deviations, and the transient voltage response for its system. For transient voltage response, the criteria must at a minimum, specify a low voltage level and a maximum length of time that transient voltages may remain below that level. *[Alberta Risk Rating: Medium] [Time Horizon: Long-term Planning]*
- M5.** The **ISO** must provide dated evidence. Evidence may include electronic or hard copies of the documentation specifying the criteria for acceptable system steady state voltage limits, post-**contingency** voltage deviations, and the transient voltage response for its system or other equivalent evidence in accordance with Requirement R5.
- R6.** The **ISO** must define and document, within their **planning assessment**, the criteria or methodology used in the analysis to identify system instability for conditions such as **cascading**, voltage instability, or uncontrolled islanding. *[Alberta Risk Rating: Medium] [Time Horizon: Long-term Planning]*
- M6.** The **ISO** must provide dated evidence. Evidence may include electronic or hard copies of documentation specifying the criteria or methodology used in the analysis to identify system instability for conditions such as **cascading**, voltage instability, or uncontrolled islanding that was utilized in preparing the **planning assessment** or other equivalent evidence in accordance with Requirement R6.
- R7.** [Intentionally left blank.]
- M7.** [Intentionally left blank.]
- R8.** The **ISO** must distribute its **planning assessment** results to adjacent planning coordinators and adjacent **transmission planners** within 90 **days** of completing its **planning assessment**, and to any functional entity that has a reliability related need and submits a written request for the information within 30 **days** of such a request. *[Alberta Risk Rating: Medium] [Time Horizon: Long-term Planning]*
- 8.1.** If a recipient of the **planning assessment** results provides documented comments on the results, the **ISO** must provide a documented response to that recipient within 90 **days** of receipt of those comments.
- M8.** The **ISO** must provide evidence, evidence may include email notices, documentation of updated web pages, postal receipts showing recipient and date; or a demonstration of a public posting, that it has distributed its **planning assessment** results to adjacent planning coordinators and adjacent **transmission planners** within 90 **days** of having completed its **planning assessment**, and to any functional entity who has indicated a reliability need within 30 **days** of a written request and that the

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ISO has provided a documented response to comments received on **planning assessment** results within 90 **days** of receipt of those comments or other equivalent evidence in accordance with Requirement R8.

C. Compliance

[Intentionally left blank]

D. Regional Variances

None

E. Interpretations

None.

F. Additional Documents

- AESO Information Document ID# 2016-006, *Radial Circuit* and any amendments made from time to time.
- AESO Information Document ID# 2020-014, *Bulk Electric System Definition* and any amendments made from time to time.
- TPL-001-PLAN-AB-1, *Implementation Plan for TPL-001-AB-5.1*

Version History

Version	Effective Date	Description of Changes
AB-5.1	2028-01-01	Revised based on NERC's latest version, TPL-001-5.1., as approved by FERC (Docket No. RD20-8-000) and to address reliability issues as identified in FERC Orders No. 754 and No. 786 directives. The revision on TPL-001-AB-0 includes merging and upgrading requirements of TPL-001-AB-0, TPL-002-AB1-0, TPL-003-AB-0, and TPL-004-AB-0 into one, single, comprehensive, coordinated standard.
AB-0	2016-08-01	Initial release.

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Table 1 – Steady State & Stability Performance Planning Events

Steady State & Stability:

- a. The system shall remain stable. **Cascading** and uncontrolled islanding shall not occur.
- b. **Consequential load loss** as well as **generating unit** and **aggregated generating facility** loss is acceptable as a consequence of any event excluding P0.
- c. Simulate the removal of all **system elements** that **protection systems** and other controls are expected to automatically disconnect for each event.
- d. Simulate **normal clearing** unless otherwise specified.
- e. Planned system adjustments such as transmission configuration changes and re-dispatch of a **generating unit** or **aggregated generating facility** are allowed if such adjustments are executable within the time duration applicable to the **facility ratings**.

Steady State Only:

- f. Applicable **facility ratings** shall not be exceeded.
- g. System steady state voltages and post-**contingency** voltage deviations shall be within acceptable limits as established by the **ISO**.
- h. Planning event P0 is applicable to steady state only.
- i. The response of voltage sensitive load that is disconnected from the system by end-user equipment associated with an event shall not be used to meet steady state performance requirements.

Stability Only:

- j. Transient voltage response shall be within acceptable limits established by the **ISO**.

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Category	Initial Condition	Event ¹	Fault Type ²	Voltage Level ³	Non-Consequential Load Loss Allowed
P0 No Contingency	Normal System	None	N/A	EHV, HV	No
P1 Single Contingency	Normal System	Loss of one of the following: 1. Generating unit or aggregated generating facility 2. Transmission circuit 3. Transformer ⁵ 4. Shunt device ⁶	3Ø	EHV, HV	No
		5. Single pole of a DC line	SLG		
P2 Single Contingency	Normal System	1. Opening of a transmission line section without a fault ⁷	N/A	EHV, HV	No
		2. Bus section fault	SLG	EHV	No
				HV	Yes
		3. Internal breaker fault ⁸ (non-bus-tie breaker)	SLG	EHV	No
HV	Yes				
4. Internal breaker fault (bus-tie breaker) ⁸	SLG	EHV, HV	Yes		

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Category	Initial Condition	Event ¹	Fault Type ²	Voltage Level ³	Non-Consequential Load Loss Allowed
P3 Multiple Contingency	Loss of generating unit followed by system adjustments	Loss of one of the following: 1. Generating unit or aggregated generating facility 2. Transmission circuit 3. Transformer ⁵ 4. Shunt device ⁶	3Ø	EHV, HV	No
		5. Single pole of a DC line	SLG		
P4 Multiple Contingency (<i>Fault plus stuck breaker</i> ¹⁰)	Normal System	Loss of multiple system elements caused by a stuck breaker ¹⁰ (non-bus-tie breaker) attempting to clear a fault on one of the following: 1. Generating unit or aggregated generating facility 2. Transmission circuit 3. Transformer ⁵ 4. Shunt device ⁶ 5. Bus section	SLG	EHV	No
				HV	Yes
		Loss of multiple system elements caused by a stuck breaker ¹⁰ (bus-tie breaker) attempting to clear a fault on the associated bus	SLG	EHV, HV	Yes

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Category	Initial Condition	Event ¹	Fault Type ²	Voltage Level ³	Non-Consequential Load Loss Allowed
P5 Multiple Contingency <i>(Fault plus non-redundant component of a protection system failure to operate)</i>	Normal System	Delayed fault clearing due to the failure of a non-redundant component of a protection system ¹³ protecting the faulted system element to operate as designed, for one of the following: 1. Generating unit or aggregated generating facility 2. Transmission circuit 3. Transformer ⁵ 4. Shunt device ⁶ 5. Bus section	SLG	EHV	No
				HV	Yes
P6 Multiple Contingency <i>(Two overlapping singles)</i>	Loss of one of the following followed by system adjustments. 1. Transmission circuit 2. Transformer ⁵ 3. Shunt device ⁶ 4. Single pole of a DC line	Loss of one of the following: 1. Transmission circuit 2. Transformer ⁵ 3. Shunt device ⁶	3Ø	EHV, HV	Yes
		4. Single pole of a DC line	SLG	EHV, HV	Yes

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Category	Initial Condition	Event ¹	Fault Type ²	Voltage Level ³	Non-Consequential Load Loss Allowed
P7 Multiple Contingency <i>(Common structure)</i>	Normal System	The loss of: 1. Any two adjacent (vertically or horizontally) circuits on common structure ¹¹ 2. Loss of a bipolar DC line	SLG	EHV, HV	Yes

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Table 1 – Steady State & Stability Performance Extreme Events

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<p>Steady State & Stability</p> <p>For all extreme events evaluated:</p> <ol style="list-style-type: none"> a. Simulate the removal of all system elements that protection systems and automatic controls are expected to disconnect for each contingency. b. Simulate normal clearing unless otherwise specified. 	
<p>Steady State</p> <ol style="list-style-type: none"> 1. Loss of a single generating unit, aggregated generating facility, transmission circuit, single pole of a DC line, shunt device, or transformer forced out of service followed by another single generating unit, aggregated generating facility, transmission circuit, single pole of a different DC line, shunt device, or transformer forced out of service prior to system adjustments. 2. Local area events affecting the transmission system such as: <ol style="list-style-type: none"> a. Loss of a tower line with three or more circuits.¹¹ b. Loss of all transmission lines on a common right of way.¹¹ c. Loss of a switching station or substation (loss of one voltage level plus transformers). d. Loss of all generating units at an generating station. e. Loss of a large load or major load centre. 3. Wide-area events affecting the transmission system based on system topology such as: 	<p>Stability</p> <ol style="list-style-type: none"> 1. With an initial condition of a single generating unit, aggregated generating facility, transmission circuit, single pole of a DC line, shunt device, or transformer forced out of service, apply a 3Ø fault on another single generating unit, aggregated generating facility, transmission circuit, single pole of a different DC line, shunt device, or transformer prior to system adjustments. 2. Local or wide-area events affecting the transmission system such as: <ol style="list-style-type: none"> a. 3Ø fault on a generating unit or aggregated generating facility with stuck breaker¹⁰ resulting in delayed fault clearing. b. 3Ø fault on transmission circuit with stuck breaker¹⁰ resulting in delayed fault clearing. c. 3Ø fault on transformer with stuck breaker¹⁰ resulting in delayed fault clearing. d. 3Ø fault on bus section with stuck breaker¹⁰ resulting in delayed fault clearing.

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<ul style="list-style-type: none"> a. loss of two generating stations resulting from conditions such as: <ul style="list-style-type: none"> i. Loss of a large gas pipeline into a region or multiple regions that have significant gas-fired generating units or aggregated generating facilities. ii. Loss of the use of a large body of water as the cooling source for a generating unit or aggregated generating facility. iii. Wildfires. iv. Severe weather, e.g., hurricanes, tornadoes, etc. v. A successful cyber attack. vi. Shutdown of a nuclear power plant(s) and related facilities for a day or more for common causes such as problems with similarly designed plants. b. Other events based upon operating experience that may result in disturbances in the wide-area. 	<ul style="list-style-type: none"> e. 3Ø fault on generating unit or aggregated generating facility with failure of a non-redundant component of a protection system¹³ resulting in delayed fault clearing. f. 3Ø fault on transmission circuit with failure of a non-redundant component of a protection system¹³ resulting in delayed fault clearing. g. 3Ø fault on transformer with failure of a non-redundant component of a protection system¹³ resulting in delayed fault clearing. h. 3Ø fault on bus section with failure of a non-redundant component of a protection system¹³ resulting in delayed fault clearing. i. 3Ø internal breaker fault. j. Other events based upon operating experience, such as consideration of initiating events that experience suggests may result in disturbances in the wide-area.
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**Table 1 – Steady State & Stability Performance Footnotes
(Planning Events and Extreme Events)**

1. If the event analyzed involves **system elements** that are part of the **bulk electric system** at multiple system voltage levels, the lowest system voltage level of the **system elements** removed for the analyzed event determines the stated performance criteria regarding allowances for interruptions of **non-consequential load loss**.
2. Unless specified otherwise, simulate **normal clearing of faults**. Single line to ground (SLG) or three-phase (3 \emptyset) are the **fault** types that must be evaluated in stability simulations for the event described. A 3 \emptyset or a double line to ground **fault** study indicating the criteria are being met is sufficient evidence that a SLG condition would also meet the criteria.
3. Voltage level references:
 - a. The designation of extra-high voltage (EHV) and high voltage (HV) is used to distinguish between stated performance criteria allowances for interruption of **non-consequential load loss**.
 - b. For categories P0 and P1, EHV facilities include **transmission facilities** energized at greater than 300 kV that are part of the **bulk electric system**. HV facilities include **transmission facilities** energized between 100 kV and 300kV that are part of the **bulk electric system**, as well as **transmission facilities** energized at 69kV or higher but below 100kV.
 - c. For categories from P2 to P7, EHV facilities include **transmission facilities** energized at greater than 300kV that are part of the **bulk electric system**, and HV facilities include **transmission facilities** energized between 100 kV and 300kV that are part of the **bulk electric system**.
4. [Intentionally left blank.]
5. For non-generator step-up transformer outage events, the reference voltage, as used in footnote 1, applies to the low-side winding (excluding tertiary windings). For **generating unit** or **aggregated generating facility** and generator step-up transformer outage events, the reference voltage applies to the **bulk electric system** connected voltage (high-side of the generator step-up transformer). Requirements which are applicable to transformers also apply to variable frequency transformers and phase shifting transformers.
6. Requirements which are applicable to shunt devices also apply to FACTS devices that are connected to ground.
7. Opening one end of a line section without a **fault** on a normally networked transmission circuit such that the line is possibly serving load radial from a single source point.
8. An internal breaker **fault** means a breaker failing internally, thus creating a system **fault** which must be cleared by protection on both sides of the breaker.

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9. [Intentionally left blank.]
10. A stuck breaker means that for a gang-operated breaker, all three phases of the breaker have remained closed. For an independent pole operated (IPO) or an independent pole tripping (IPT) breaker, only one pole is assumed to remain closed. A stuck breaker results in delayed **fault** clearing.
11. Excludes circuits that share a common structure (Planning event P7, Extreme event steady state 2a) or common right of way (Extreme event, steady state 2b) for 1 mile or 1.609 kilometres or less.
12. [Intentionally left blank.]
13. For purposes of this **reliability standard**, non-redundant components of a **protection system** to consider are as follows:
 - (a) A single protective relay which responds to electrical quantities, without an alternative (which may or may not respond to electrical quantities) that provides comparable **normal clearing** times;
 - (b) A single communications system associated with protective functions, necessary for correct operation of a communication-aided protection scheme required for **normal clearing** (an exception is a single communications system that is both monitored and reported at a **control centre**);
 - (c) A single station dc supply associated with protective functions required for **normal clearing** (an exception is a single station dc supply that is both monitored and reported at a **control centre** for both low voltage and open circuit);
 - (d) A single control circuitry (including auxiliary relays and lockout relays) associated with protective functions, from the dc supply through and including the trip coil(s) of the circuit breakers or other interrupting devices, required for **normal clearing** (the trip coil may be excluded if it is both monitored and reported at a **control centre**).

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Attachment 1

Stakeholder Process

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